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APPLICATION FOR UNITED STATES LETTERS PATENT

FOR

SYSTEMS AND METHODS FOR CONTROLLING FLOW CONTROL DEVICES

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CROSS-REFERENCE TO RELATED APPLICATIONS

None.

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates to control systems and methods for fluid extraction from oil and gas wells. More particularly, the present invention relates to methodologies for controlling a downhole pump in an oil or gas well to optimize the fluid removal process and/or gas, oil, or water production. In another aspect, the present invention relates to systems and devices for optimal control of a flow control device. In yet another aspect, the present invention relates to systems and methods for monitoring and recording physical changes in a fluid body.

2. Description of the Related Art

Hydrocarbons (*e.g.*, oil and gas) are recovered by drilling a wellbore in a subterranean formation having one or more hydrocarbon reservoirs. Under formation pressure or by artificial lift, the hydrocarbons flow up the wellbore and are recovered at the surface, a process commonly referred to as hydrocarbon production. In many instances, downhole devices such as pumps are used to assist in hydrocarbon production. For example, pumps are often used to control the levels of fluids in the wellbore (*e.g.*, water, gas, oil), to provide a pressure boost to flow the wellbore fluids to the surface or other location, or to otherwise adjust the wellbore environment to maintain efficient production. Wellbore pumps are used in a number of applications, including: conventional oil production, heavy oil production, gas-dewatering, , and coal-bed methane production.

Coal-bed methane production is illustrative of some aspects of wellbore or downhole pumps and associated control devices. Coal bed methane is methane that is found in coal seams. Methane is a significant by-product of coalification, the process by which organic matter becomes coal. Often the coal seams are at or near underground water or aquifers, and coal bed methane production is reliant on manipulation of underground water tables and levels. The underground water often saturates the coal seam where methane is found, and the underground water is often saturated with methane. The methane may be found in aquifers in and around coal seams, whether as a free gas or in the water, adsorbed to the coal or embedded in the coal itself. Methane is a primary constituent of natural gas. Recovery of coal bed methane can be an economic method for production of natural gas. Such recovery is now pursued in geologic basins around the world. However, every coal seam that produces coal bed methane has a unique set of reservoir characteristics that determine its economic and technical viability.

Methods of coal bed methane recovery vary from basin to basin and operator to operator. However, a typical recovery strategy is when a well is drilled into the coal seam, usually a few hundred to several thousand feet below the surface. Thereafter, a casing is set and cemented in place and a water pump and gas separation device are installed. The water pump is operated to remove water from the coal seam at a rate appropriate to reduce the hydrostatic pressure exerted on the formation fluids. When the hydrostatic pressure is sufficiently low, the methane desorps from the coal. However, because the rate of desorption varies roughly inversely with the exerted hydrostatic pressure, dropping the hydrostatic pressure too low may result in a rate of methane production that can overwhelm the methane recovery equipment. Thus, control over the water head or height of a water column in the well is a significant factor in the production of methane.

In conventional coal-seam gas wells, submersible pumps with variable speed controllers are used as liquid removal systems. Typically, these pumps are controlled in response to a determination of the water level in the wellbore. A conventional arrangement includes a liquid level sensor that uses a pressure responsive switch. For instance, the system can have an electrical control circuit including a switch which operates to turn on the water pump motor when the water level in the well reaches a certain high level (as measured by the pressure responsive switch) and to turn off the pump motor the water level reaches a certain low level in the well. These sensors are exemplary of mechanical sensors—*i.e.*, sensors that mechanically co-act with the sensed fluid in order to measure a condition in the wellbore (*e.g.*, the presence or absence of surrounding water). For example, an element of a pressure switch moves or compresses in response to hydrostatic pressure or a float member of a float switch moves in response to buoyancy force. The mechanical and electrical elements of such mechanical devices can be prone to sticking, wear and corrosion. Thus, a long-standing and persistent drawback of such sensors is that their operating life can be much shorter than the life of a production well. The cost accompanying the cessation of gas or oil production to repair or replace an inoperative sensor can be significant.

Pump control devices utilizing mechanical sensors encounter similar modes of failure when used in conventional oil pump control, heavy oil pump control, and gas-dewatering pump control. In these applications as well, production objectives such as maintaining a fluid level between specific levels to optimize the production, avoiding pumping the well off, optimizing energy consumption, and reducing wear and tear on the pump are in large measure contingent upon reliable devices and methodologies for controlling downhole pumps and other such devices. More generally, the need to reliably control pump operation arises in other applications such as refineries, water treatment plants, chemical production facilities, underground gas or liquid, storage caverns,

and other instances wherein the level / quantity / flow rate / velocity of fluid is controlled or wherein the mixture or ratio of fluids is controlled.

The present invention addresses these and other drawbacks of the prior art.

SUMMARY OF THE INVENTION

In one aspect, the present invention provides a device for determining a location of an interface between a first fluid and second fluid, such as in a wellbore, a storage tank, a cavern, etc. The device includes a non-mechanical sensor that measures a selected parameter of interest relating to the fluid surrounding the sensor ("the surrounding fluid") and a processor for processing the sensor measurements. The non-mechanical sensor does not utilize motion or a physical co-action between the surrounding fluid and the sensor to produce a measurement. Rather, the non-mechanical sensor measures parameters such as thermal properties (*e.g.*, thermal conductivity or capacity), electrical properties (*e.g.*, resistance, capacitance, inductance, etc.), fluid properties (*e.g.*, viscosity), and magnetic properties. Because liquids and gases have distinct and identifiable differences in such properties, the processor can be programmed to process the sensor measurements to identify one or more characteristics in the measurements that can indicate the nature of the fluid being measured. Once the nature of the fluid is identified (*e.g.*, whether the fluid is water, oil, methane, etc.), the location of the interface can be determined. The determined location can be used for any number of purposes, including, but not limited to, real-time monitoring via a display device, recorded for long-term reservoir characterization, or for actuating an alarm if a pre-set condition is met.

In one embodiment directed to wellbore fluids, the system includes a sensor positioned in the wellbore and a processor in communication with the sensor. The sensor includes a temperature probe for measuring the temperature

of a surrounding fluid. In certain embodiments, the sensor heats the surrounding fluid while measuring temperature. The heating element can be the probe itself or a separate element. The processor processes the temperature measurements to identify the state or nature of the surrounding fluid, *e.g.*, whether the fluid is gas (*e.g.*, methane) or a liquid (*e.g.*, water). For instance, the processor can develop a curve based on the temperature measurements and then identify curve characteristics (*e.g.*, amplitudes, differentials, slopes, etc.) that are indicative of a liquid or a gas.

In another aspect, embodiments of the invention can be used to control a downhole fluid control device such as a pump or valve. In one arrangement, two non-mechanical fluid level sensors are positioned in spaced-apart relation in a wellbore having a water column. The height of the water column is adjusted by selective operation of a downhole pump. During use, a controller operatively coupled to the non-mechanical fluid level sensors determines whether one or both of the non-mechanical sensors are surrounded by water or a gas. After making this determination, the controller alters the operation of the pump (if needed) to bring the height of the water column into a selected range or height. The level sensors can be positioned physically at the operating switch points for the pump (*e.g.*, the upper and lower limits for the height of the water column). Alternatively, the level sensors can be positioned within the upper and lower limits of the water column height. For instance, the processor can determine the rate of change of the height of the water column and predict by interpolation or extrapolation the height of the water column. The processor can, optionally, also use measurements from other sensors that relate to hydrocarbon production, water production, and wellbore conditions.

It should be understood that examples of the more important features of the invention have been summarized rather broadly in order that detailed description thereof that follows may be better understood, and in order that the contributions to the art may be appreciated. There are, of course, additional

features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

For detailed understanding of the present invention, references should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals and wherein:

FIG. 1 schematically illustrates an elevation view of one embodiment of a well having a pump control system made according to one embodiment of the present invention;

FIG. 2 schematically illustrates a sectional view of a sensor made according to one embodiment of the present invention;

FIG. 3 shows an exemplary temperature versus time graph for a **Fig. 2** sensor;

FIG. 4 schematically illustrates a pump control circuit made according to one embodiment of the present invention;

FIG. 5 schematically illustrates an elevation view of another embodiment of a well having a pump control system made according to the present invention; and

FIG. 6 schematically illustrates an elevation view of yet another embodiment of a well having a pump control system made according to the present invention.

Similar reference characters denote corresponding features consistently throughout the attached drawings.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

The present invention relates to devices and methods for controlling equipment, such as pumps, used to recover hydrocarbons (*e.g.*, methane) from subterranean formations. The control systems and methods can apply to any artificial or natural lift technique, including but not limited to gas-lift, PCP pump, ESP pump, rod pump, downhole control valves for selective zone control. The present invention also relates to devices and methods for determining the location of an interface between a first liquid and a second liquid. The present invention is susceptible to embodiments of different forms. There are shown in the drawings, and herein will be described in detail, specific embodiments of the present invention with the understanding that the present disclosure is to be considered an exemplification of the principles of the invention, and is not intended to limit the invention to that illustrated and described herein.

As will become evident in the discussion below, embodiments of the present invention may be used to enhance the production of methane from subterranean formations such as coal bed or enhance the production of oil from conventional or heavy oil formations. Referring initially to **Figure 1**, there is shown a facility for recovering methane from a subterranean formation. In one embodiment, the methane recovery facility **10** includes a cased well **12** that intersects a coal bed **14**. Suspended or hung within the cased well **12** is a production tubing **16**. The well **12** is partially filled with water that continually drains out of the formation, the water line being designated by numeral **18**. A pump **20** connected to an end of the production tubing **16** is used to pump water out of the cased well **12** to the surface or other locations (e.g., a subsurface formation). Operation of the pump **20** controls the height of the water column **21** and therefore the hydrostatic pressure exerted on the coal bed **14**. When the

hydrostatic pressure drops below a particular level or amount, methane **22** flows out of the formation **14** via an annulus **24** formed by the production tubing **16** and cased well **12**. Methane **22** is collected at the wellhead **26** and piped or otherwise transported for further refinement.

It will be appreciated that if the water level in the case well **12** is sufficiently high, the resulting hydrostatic pressure will suppress or extinguish the production of methane **22**. On the other hand, if the water level **18** drops too low, such as below the pump **20**, the pump **20** may be damaged. Moreover, the loss of hydrostatic pressure can lead to an excessive release of methane and an over pressure situation in the well **12** and at the wellhead **26**. Thus, the wellbore can be considered to have two fluids: a gas (*e.g.*, methane) and a liquid (*e.g.*, water). The location of the interface between these two fluids impacts the production of the hydrocarbons residing in the formation.

In one embodiment, a pump control system **30** for controlling pump operation includes a lower level sensor **32**, an upper level sensor **34**, a telemetry cable **36** and a controller **38**. The controller **38** periodically communicates with the level sensors **32** and **34** to determine whether operation of the pump **20** should be adjusted in response to changes in the height of the water column **21** (*i.e.*, shifts in location of the water-gas interface). A number of arrangements may be employed to make this determination.

In one arrangement, the controller **38** is programmed to energize and de-energize the pump **20** upon detecting one or more predetermined conditions. For instance, a first predetermined condition may be a height of a water column **21** below a first depth **D1**. It may be determined that a water column **21** below the first depth **D1** may apply insufficient hydrostatic pressure to the formation or raise the risk that the pump **20** may not be fully submerged. Thus, the lower sensor **32** is positioned at the first depth **D1**. A second predetermined condition may be a water column **21** having a height at or above a second depth **D2**, a

height causing a hydrostatic pressure that unacceptably impairs the production of methane. Therefore, the upper sensor **34** is set at the second depth **D2**. During operation, the controller **38** periodically interrogates each sensor **32, 34**. Based on the sensor response, the controller **38** determines whether either the first or second predetermined condition is present and, if needed, takes appropriate action. Thus, the first and second depths **D1**, **D2** are pre-determined set-points that are used to adjust the operation of the pump **20**.

There are several actions that can be taken by the controller **38** after interrogating the sensors **32, 34**. For instance, the controller **38** can be programmed to de-energize the pump **20** if the response of the lower sensor **32** indicates that the water level is at or below the lower sensor **32** and energize the pump **20** if the response of the upper sensor **34** indicates that water level **18** is at or above the upper sensor **34**. In other embodiments, the controller **38** can include a timer that energizes or de-energizes the pump **20** after a pre-set time delay. In still other embodiments, the controller **38** can be programmed to adjust (*e.g.*, increase or decrease) the flow rate of the pump **20** in response to the detected predetermined condition.

In certain embodiments, the controller **38** can be configured to provide intelligent control of the pump **20** based on measurements relating to one or more parameters of interest. In one embodiment, the controller **38** can include microprocessors having programs for optimizing operation of the pump **20.** For instance, the controller **38** can be programmed to calculate the rate of change of the height of the water column **21** by measuring the time required for the water column **21** to transition between the lower sensor **32** and the upper sensor **34**. The controller **38** can utilize the results of this calculation to determine whether the pump **20** should be energized / de-energized, whether a time delay should be used before adjusting operation of the pump **20**, and/or to determine the type and magnitude of adjustment to the flow rate of the pump **20**.

Additionally, in certain embodiments, parameters of interest relating to methane or water production and/or wellbore conditions may be utilized by the controller **38** to optimize operation of the pump **20**. For example, a sensor **39** at the wellhead **26** (or other location) can provide information on production flow rate of methane and/or water to the controller **38**. Parameters relating to wellbore conditions include fluid inflow, pressure and temperature. Optimization models provided in the controller **38** can utilize this information to maintain the height of the water column **21** within a pre-determined or calculated optimal range. It should be appreciated that what constitutes optimal operation can vary with the operator, application and other factors. Exemplary optimal operation can include maximizing methane production, minimizing cycling of the pump **20**, minimizing the operating time of the pump **20**, and reducing the risk of running the pump dry (thus damaging the pump), etc.

Referring now to **Fig. 2** there is shown one embodiment of a level sensor **50** suitable for use in the control system **30** (**Fig. 1**). The sensor **50** includes a probe **52** that produces a signal indicative of the thermal property of the wellbore fluid in which it is immersed. Wellbore fluids can include liquids such as water and gases such as methane. During production, the wellbore fluids such as methane can have relatively high flow rates. In many instances, positioning the probe directly within the flowing gas can degrade the capacity of the sensor **50** to make accurate measurements. Therefore, in some embodiments, one or more probe shields **54** having vent holes **56** surrounds the probe **52**. For illustrative purposes only one shield **54** is shown. The shield **54** protects the probe **52** by shielding it from direct splashing and exposure to vigorously turbulent or bubbling wellbore fluids and high velocity gas. The vent holes **56** allow the wellbore fluids to enter the shield **54** and envelope the probe **52**, but keep the probe protected from liquid splash and out of the direct channel of flowing gas. The cable **36** is coupled to the probe **52** by a suitable wiring **38**. In certain embodiments, telemetry systems using RF, EMF, pressure waves or acoustics may be used in lieu of or in addition the wiring **38**. A pressure seal **42** may be used to insulate

the electrical connection between the cable **36** and the probe **52**. In certain applications, the cable **36** includes a mono-conductor cable. Thus, to operate two probes over the mono-conductor cable, the sensor **50** includes a diode **40** to allow selective control over either of the probes. In certain applications other sensors may be combined with the system on a separate or same cable to produce a combination of measurements. One such example of this is the addition of a down-hole pressure sensor.

One illustrative probe **52** is a resistance temperature detector RTD probe, the use of which is described below. RTD is defined as any resistance temperature detector. It consists of a resistive element that changes its electrical resistance as the temperature changes. This is commonly referred to as a platinum resistor, RTD, or thermistor. Other devices also change their resistance due to temperature that can be made from copper, nickel or nickel-iron, or any other electrical conductor that changes its resistance with respect to temperature. Referring now to **Figs. 1-3**, in one mode of operation, the controller **38** initiates the transmission of a signal, such as an electrical signal, via the cable **36** to the RTD probe **52**. In one arrangement, the controller **38** is programmed to measure the temperature differentials created by repetitively heating the probe **52** and letting it cool down to ambient temperature. Fluid has both a higher thermal capacity and thermal conductivity. Both properties influence the thermal loading effect. An RTD probe changes its electrical resistance with respect to temperature and therefore an indication of temperature can be obtained by several methods using applied current and voltage to the probe. The resultant measurement represents a change in resistance of the probe that proportionally is a measure of the effective temperature of the probe.

Fig. 3 illustrates an exemplary temperature versus time curve **60** for such cyclic heating and cooling of the probe **52**. As can be seen the temperature curve **60** has two distinct portions. One portion **62** represents the response of the probe **52** when immersed in a gas (*e.g.*, air or methane) and the other portion

64 represents the response of the probe **52** when immersed in fluid. In the exemplary curve **60**, the probe **52** is energized at point **66.** Because the probe **52** is immersed in gas, the resulting thermal loading is relatively light and allows the probe **52** to have a relatively substantial increase in temperature. Heating is terminated at point **68** to allow the probe to cool to ambient. Again, the probe **52** displays a relatively large temperature drop due to its immersion in gas. The heating and cooling can be repeated as needed to gather sufficient information to characterize the behavior of the probe **52**. At point **70**, the probe **52** becomes immersed in a fluid. Heating at point **72** of the probe **52** results in a relatively lower temperature increase due to the relatively high thermal loading caused by the water. At point **74**, the probe **52** is de-energized and allowed to cool to ambient temperature. In like fashion, the temperature drop is relatively small because of the high thermal loading caused by the fluid. It should be appreciated that the temperature differential between points **66** and **68** is greater than the temperature differential between points **72** and **74**. Thus, by measuring the temperature differential, the controller **38** can determine whether the RTD probe **52** is immersed in water or is above water line **18**. It should be appreciated that no mechanical co-action is needed between any component of the sensor **50** and the fluid being sensed; *i.e.*, no element of the sensor **50** is designed to mechanically move in order to make a measurement. Thus, advantageously, the risk that the sensor **50** will suffer a premature failure is reduced because a prevalent mode of failure (mechanical failure) has been largely eliminated.

In another arrangement the sensor may include a first element for heating the surrounding fluid and a second element for measuring the temperature (or temperature change) in the surrounding fluid. With this methodology a similar result of identifying the difference in thermal properties between the gas and fluid can be achieved. This arrangement can allow for measurement of thermal conductivity or heat capacity. Both properties are substantially different and uniquely identifiable in the two mediums.

It should be understood that other methodologies can be employed to determine the nature and magnitude of a given thermal loading. For example, the curves connecting points **66** and **68** and points **72** and **74** may have unique and distinct characteristics; *e.g.*, different slopes, different rates of change of slopes during heating or cooling, etc. Thus, analysis and quantification of the characteristics of the curves can lead to additional methods for use in determining thermal loading (*e.g.*, measuring rate of change of slopes, frequency change, curve characteristics). In addition to using the distinctive thermal properties of liquids and gases such as thermal conductivity, specific heat, and head capacity, as a criteria for determining the type of fluid in which a probe is immersed, other properties such as resistivity, conductivity, capacitance, inductive, magnetic, electromagnetic, optical, viscosity, density, surface tension, compressibility speed of sound, sonic impendence, fluid or gas properties and chemical properties may be used as the basis for making such determinations.

Referring now to **Fig. 4,** there is shown an exemplary control system utilizing the sensors **32, 34**. The system of **Fig. 4** includes the upper level sensor **34**, the lower level sensor **32**, the processor or controller **38**, a power source such as a current source **80**, and a pump control unit **82**. The sensors **32, 34,** processor **38** and the current source **80** are operably coupled by a suitable data conduit or carrier **36**. In response to a command signal issued by the processor **38**, the current source **80** generates an electrical signal for heating the sensors **32, 34**. The current output by the source **80** is also used for doing a two-point resistance measurement utilizing the sensors **32** and **34.** The processor **38** measures the response of the sensor **32, 34** to determine whether their thermal loading is indicative of a surrounding gas or liquid. Based on the determination, the processor **38** operates a pump control unit **82** having one or more relays **84** that are coupled to the pump (not shown). For example, the processor **38** opens and closes the relays **84** as necessary to control the operation of the pump (not shown). The pump controller may also communicate directly with the processor **38** via a direct digital interface, serial or parallel data bus or analog data transfer.

(not shown). Diodes **86, 88** can be used to selectively energize or actuate the sensors **32**, **34** (*i.e.*, the sensors **32**, **34** operate at opposite polarities). In addition to being advantageous where a carrier **36** includes a mono-conductor, such an arrangement also readily allows the substantially simultaneous heating of one sensor and the cooling of the other sensor.

Referring now to **Fig. 5**, there is shown another embodiment of the present invention using a single sensor **90** operable coupled to a downhole control unit **92** for operating a pump **94**. Merely for illustrative purposes, the single sensor **90** is shown having a heating element **91a** separate from a temperature probe **91b**. In the **Fig. 5** embodiment, the control unit **92**, in one mode of operation operates the pump **94** until a specified condition has been met, *e.g.*, the response of the sensor **90** indicates that the height of the water column **96** has dropped below the sensor **90**. Upon occurrence of the condition, the control unit **92** stops operation of the pump **94**. The control unit **92** can be programmed to re-initiate operation of the pump **94** after a pre-set or predetermined time delay, or after the water column **96** has reached a specified height, or the detection of some other specified condition. Additionally, the control unit **92** can include microprocessors that process measurements of parameters relating to wellbore conditions or production to optimize control of the pump **94**. The control unit **94** can be programmed to operate in a closed loop fashion (*i.e.*, automatically) or with human intervention. The power source (not shown) for activating (*e.g.*, heating and resistivity measurements) the sensor **90** can be integrated into the control unit **94** or can be constructed as a separate unit. Moreover, power can be transmitted from a surface source (not shown) or provided from a local source such as a battery, or obtained from the power provided on the cable driving a downhole electrical submersible pump (not shown).

Further, it should be appreciated that the teachings of the present invention extend beyond controlling downhole devices. The control unit **92** can

transmit data to surface equipment such as a display device **93a**, an alarm **93b** or a data recorder **93c** via a suitable telemetry link **95** (*e.g.*, hard-wire, acoustic signals, RF, EMF, etc.). The display device **93a** can be used to provide the operator with a real-time or near real-time indication of the location of the fluid interface. The alarm **93b** can be configured to signal that a predetermined condition has been detected in the well. The data recorder **93c** can be used to recorded liquid interface movement data, as well as other data such as production rates, wellbore conditions (*e.g.*, pressure, temperature, etc.) that can be used for extended monitoring of the reservoir. It should be understood that the display device **93a**, an alarm **93b** or a data recorder **93c** are merely illustrative of devices that utilize the information provided by the fluid level sensor **90** for purposes other than controlling downhole devices. Devices such as these (separately or in combination) can be used in addition to or in lieu of a control unit for operating a downhole device such as a pump.

Referring now to **Fig. 6**, in certain embodiments, a pump control system **100** operates a pump **102** based on an estimated height for a water column **104**. The control system **100** includes a first sensor **106,** a second sensor **108** and a control unit **110**. The control unit **110** is programmed with pre-determined switch-points **P1** and **P2** for controlling the pump **102**. The points **P1** and **P2** are points that if reached by the water column **104** will trigger an adjustment to pump operation (*e.g.*, increasing/decreasing flow rate). The sensors **106**, **108** are not positioned at the points **P1** and **P2**. Rather, the sensors **106**, **108** are position within the points **P1** and **P2**. As will be discussed below, the control unit **110** utilizes the measurements from the sensors **106**, **108** to extrapolate the height of the water column **104** and, based on this extrapolation, operate the pump **102**.

In one method of operation, the control unit **110** measures the time needed for the fluid level to transition between the two sensors **106**, **108**. Based on this measurement, an effective inflow rate, an effective pump-off rate, or differential of the inflow and pump-off rate can be determined. Using this

information, the control unit **110** can calculate a rate of change (*e.g.*, increase or decrease) of the height of the water column **104**. Based on this calculated rate of change, the control unit **110** can estimate the time required for the height of the water column to reach point **P1** from sensor **108** or point **P2** from sensor **106**. The estimated time, in turn, is used to adjust operation of the pump, *e.g.*, setting the optimal time to energize or de-energize the pump, selecting an optimal adjustment to the pump flow rate, etc. In certain applications, the control unit **110** can use additional data such as known wellbore / production tubing geometry (*e.g.*, internal volume of the wellbore), a known inflow or pump off relationship, and measurements from other sensors (*e.g.*, pressure sensors) in the wellbore in the calculations. It should thus be appreciated that the **Fig. 6** embodiment creates a "virtual" sensor position extending well beyond one or both of the physical sensor positions.

In another mode of operation, the control unit **110** uses the calculated rate of increase / decrease in the height of the water column **104** to interpolate between the two sensors **106,108** to determine the height of the water column **104**. Thus, at any given time, the control unit **110** can determine the approximate height of the water column **104.** This information can be used to provide enhanced control over the pump **104**. For example, the flow rate of the pump **104** can be adjusted to maintain a specified height for the water column **104**. It should also be appreciated that the switch points **P1** and **P2** can be adjusted over time to account for changes in the reservoir. Further, both sensors **106, 108** need not be within switch points **P1** and **P2**. For instance, in some embodiments, one of the sensors **106** or **108** is positioned at the switch point **P2** or **P1**.

From the above, it should be appreciated that the teachings of the present invention include, but are not limited to, systems and methods for investigating the nature of materials, such as wellbore fluids, in a well adapted to produce hydrocarbons. While sensors for measuring thermal loading have been

discussed above, any non-mechanical sensor adapted to produce distinct and different responses upon encountering a gas or liquid may used to achieve a similar functional control. By "non-mechanical" it is meant a sensor that does not utilize motion or a physical co-action between the sensed fluid and the sensor to produce a measurement. As discussed previously, mechanical sensors such as pressure transducers employ mechanical parts that, due to repeated movement and/or a harsh, corrosive wellbore environment, tend to prematurely fail.

Additionally, the control systems utilizing such non-mechanical sensors are not limited to only downhole pumps. For instance, in certain embodiments, such sensors can be positioned inside production tubing extending through multiple production zones. One or more flow control devices (*e.g.*, valves) can be used to control the in-flow of formation fluids at each of the production zones. A control unit uses the measurements from the sensors to identify the nature and make up of the fluid in the tubing (*e.g.*, determining gas-oil, gas-water, or oil-water ratios). Based on the determinations, the control unit issues appropriate control signals to a flow control device such as a valve to adjust in-flows.

It should also be appreciated that the teachings of the present invention are not limited to any particular number of sensors. For example, in certain applications three or more sensors may be used. Indeed, some applications requiring a relatively precise determination of a fluid level height may utilize dozens or hundreds of sensors. For instance, a ribbon-like member can be overlaid with resistive elements distributed at spaced-apart intervals. In such arrangements, an enabling device can be configured to selectively enable the resistive elements in a manner that identifies the location of the first liquid-second liquid interface. The enabling device can, for example, utilize a specified voltage level, frequency and/or polarity to selectively enable the sensors. Additionally, the sensors can be addressable in certain applications to facilitate selective enablement of a plurality of sensors.

From the above, it should be appreciated that the teachings of the present invention include one or more non-mechanical fluid level sensors that are strategically deployed in body of fluid. While the described embodiments are described in the context of fluids in a wellbore, the sensed fluids can be in an underground storage tank, a storage cavern, or an above-ground tank. Moreover, the fluid can be a natural body of water (such as a lake or stream) or a body of water that are created during special circumstances (*e.g.*, flood waters in an under-pass for a road). Indeed, the teachings of the present invention can be advantageously applied in nearly any situation where it is desirable to monitor, record or take responsive action to changes in height of a body of fluid. Furthermore, while embodiments of the present invention were discussed in connection with determining the location of gas-water interface, the present teachings can also be used to determine the location of a liquid-liquid interface (*e.g.*, a water-oil interface).

The foregoing description is directed to particular embodiments of the present invention for the purpose of illustration and explanation. It will be apparent, however, to one skilled in the art that many modifications and changes to the embodiment set forth above are possible without departing from the scope and the spirit of the invention. It is intended that the following claims be interpreted to embrace all such modifications and changes.